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VIA EMAIL/HAND DELIVERY

To: The Commissioners, Parties and Intervenors:

RE: Service List 06-241 RFP/IRP

In connection with the above-referenced proceeding, on behalf of Delmarva Power & Light Company ("Delmarva Power"), attached please find a report prepared by Concentric Energy Advisors entitled: *An Assessment of the Risks of the Independent Consultant's Proposed Modifications to Delmarva's RFP for New Generation Resources*. This filing is made in response to the Public Service Commission of Delaware's invitation to file comments / clarify the record on then open matters following the October 31, 2006, Commission hearing.

- 1) The proper percentage of imputed debt to apply to bids under evaluation; and
- 2) Whether to apply a cap on the letter of credit, which will be posted by the seller to cover 2 years of operations of what could be a 25-year contract.

To summarize the key exhibits, Exhibit – JJR-1 and Exhibit - JJR-2 from the Report examine the issues of Imputed Debt and the Capping of Liability as addressed in other RFPs. Additionally, Delmarva Supplemental Exhibit 1 and Delmarva Supplemental Exhibit 2 provide Delmarva Power's proposed order language. Please note, the goal of the Report and the Exhibits is not to reargue issues already decided by the Commission, such as whether bids up to 400 MW will be permitted. Rather, the report highlights the impact such large bids would have on imputed debt and the need operational security. As such, Delmarva is hopeful that the report and the exhibits will assist the Commission in resolving these open issues.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Anthony C. Wilson", written over a horizontal line.

Anthony C. Wilson

cc: DE PSC Commissioners
Bruce Burcat
Connie McDowell
Janis Dillard

James McC. Geddes, Esquire
G. Arthur Padmore

Attachment A

Report prepared by Concentric Energy Advisors entitled: *An Assessment of the Risks of the Independent Consultant's Proposed Modifications to Delmarva's RFP for New Generation Resources*

**An Assessment of the Risks of the Independent
Consultant's Proposed Modifications to Delmarva's
RFP for New Generation Resources**



**CONCENTRIC
ENERGY ADVISORS**

October 30, 2006

Prepared For:

Orrick, Herrington & Sutcliffe LLP

on behalf of

Delmarva Power & Light Company

I. EXECUTIVE SUMMARY

Introduction

Concentric Energy Advisors, Inc. (“CEA”) has been retained by Delmarva Power & Light Company (“Delmarva” or “the Company”) to review and comment on Delmarva’s pending Request for Proposals for New Generation Resources (“the RFP”). We understand that, in compliance with the Electric Utility Retail Customer Supply Act of 2006 (“the Act”), Delmarva filed a draft RFP on August 1, 2006. We also understand that the Delaware Public Service Commission (“the Commission”) has retained an independent consultant as a market monitor for the RFP process (“the Independent Consultant”), and that the Independent Consultant has recommended modifications to the draft RFP in initial and final reports to the Commission dated September 18, 2006 and October 12, 2006, respectively (together, “the Consultant Report”).

The purpose of this report is to provide the Commission an objective review and summary of the risks that Delmarva and its customers will be shouldering if the current recommendations of the Independent Consultant with respect to credit and security are adopted in Delmarva’s final RFP.

CEA’s staff has extensive experience in power supply procurement and power project economics, with specialization in the financial and economic issues surrounding wholesale power markets. CEA is currently advising several clients on competitive bidding processes and power procurement issues. For example, CEA is currently working with CMS Energy on the sale of the Palisades generating station and the associated long-term PPA, and also with WE Energies on the market test for the Point Beach station. In each case, CEA has worked with the bidders and the companies to develop long term power purchase agreements to repurchase power from these facilities. In addition, CEA has recently filed testimony on behalf of Xcel Energy Inc. that discusses industry norms for terms and conditions of power supply agreements.

Over the past ten years, CEA staff members have advised clients on numerous competitive bidding processes for generation assets as well as power supply agreements. CEA staff members have been extensively involved in the sale of over \$15 billion in generating assets, including the Delmarva generating assets and the PEPCO generating assets, and advised NStar in the \$1.4 billion buyout of its above market PPAs. CEA managed OG&E’s development and submission of a bid into Public Service Oklahoma’s competitive power supply procurement RFP. OG&E’s bid was specifically structured to reflect the costs and risks associated with developing a new coal-fired power plant. Having selected the winning bid, CEA is now supporting OG&E’s application for regulatory approval of the proposed power plant. CEA staff members provided testimony to the U.S. Bankruptcy Court in the Mirant bankruptcy proceeding on the appropriate interpretation of the terms and conditions of a Facility Capacity and Credit Agreement and the resulting value implications.

Overview of Findings

Delmarva has carefully constructed its proposed RFP, bidder evaluation process and PPA term sheet as a coherent package that fully satisfies the requirements of the Act. The proposed package is designed specifically in the context of Delmarva's integrated resource plan ("IRP") and credit profile, as well as the unique regulatory environment in the State of Delaware. In attempting to modify individual pieces of this package, the Independent Consultant has gone beyond this context, relying on and specifically referring to models of RFP processes used by other utilities in other states that do not face Delmarva's current situation.

To be sure, we are not, on behalf of Delmarva, rearguing issues already decided by the Commission. Rather, we attempt to provide the Commission with a context in which to consider the three open issues, namely operational security, imputed debt and variable interest entity issues. For example, the need for heightened security requirements and the level of imputed debt are greater given the potential for proposals for contracts up to 400 MW, as decided by the Commission. As a result, we find:

1) There are significant risks in adopting the credit and security recommendations/modifications of the Independent Consultant.

Many of the recommendations in the Consultant Report will subject Delmarva and its customers to substantial and unnecessary risk if they are incorporated in the final RFP. Below is a summary of the primary risks that are brought to the RFP by the recommendations of the Independent Consultant, along with the possible effects on Delmarva and its customers if these risks are realized:

- **Accepting a bid for a 400MW non-firm PPA would be too big for Delmarva's load.**
 - This level of commitment could create an aggregate fixed-cost obligation for Delmarva of more than **\$6.0 billion**¹ over the 25 years of the PPA
 - This level of commitment heightens the market risk of having to remarket excess energy
- **There is an inherently high level of market risk in a 25-year contract.**
 - This term creates a high likelihood of contract price divergence from market prices
 - If the market price falls below the contract price there will be customer migration absent adequate protections
- **There is a high likelihood of counterparty default if below-investment-grade entities are permitted to bid.**

¹ This estimated aggregate fixed cost payment is based on a bid recently submitted by a new IGCC project to Xcel Energy in Minnesota. This amount is a conservative estimate, given the likely higher construction costs in Delaware. (See Direct Testimony of John J. Reed, In the Matter of a Petition by Excelsior Energy Inc. for Approval of a Power Purchase Agreement Under Minn. Stat § 216B.1694, Minnesota Public Utilities Commission, Docket No. E6472/M- 05-1993).

- Over a 20-year period, there is a 30% chance of default for a company with a Ba Moody's rating (the most credit-worthy of the non-investment-grade ratings)
- **Bids will likely be front-end loaded.**
 - This pricing profile increases likely damages due to early termination, because Delmarva may never get to the "good" years
- **High capital cost projects are likely to have a high capacity price component.**
 - This type of bid increases Delmarva's fixed costs commitments
- **Bids are likely to include new higher-risk technologies.**
 - Increases the risk of counterparty default due to technical failure
 - A high capital cost of the likely technologies leads to a high capacity price, increasing the need to operate the unit at a very high capacity factor in order for the PPA to be economic

The security provisions proposed by the Independent Consultant are inadequate given the heightened default and operating risks listed above.

2) These risks are particularly acute for Delmarva and its Customers.

- Delmarva has \$650 million in equity capital, relative to the potential of an estimated \$6 billion PPA fixed cost obligation.
- Delmarva is rated BBB-/Baa2, one step away from non-investment-grade.
- Unlike other markets referenced in the Consultant's report, Delmarva's market is fully competitive – customers will migrate if market prices are below SOS rates. An above market PPA will cause SOS service to be above market.
- Delmarva lacks the corporate structure and resources to adequately manage the variability and risk of a 25-year 400MW unit-specific, unit-contingent contract.

3) These risks are real.

There are many cases in recent history where utilities that have absorbed similar risks have been subject to either counterparty default, high wholesale market prices with fixed low SOS prices, and/or low wholesale prices with customer migration, sometimes leading to downgrades, liquidity crises and, in several cases, bankruptcy.

Examples include:

- **Niagara Mohawk – Absorbed Long-term Contract Risk:** Restructured out-of-market contracts at a **cost of \$3.9 billion in cash and 20.5 million shares of stock** in payment to Independent Power Producers.
- **Enron's Counterparties – Absorbed Enron Credit Risk:** The well-known Enron bankruptcy **cost its counterparties an estimated \$6.3 billion**, including \$900 million related to contracts with energy companies.

- **PG&E NEG – Absorbed Liquidity Crisis Risk:** A series of short-term debt payments combined with an over-supply of merchant generation pushed NEG into a liquidity crisis and ultimately into bankruptcy in 2003.
- **California Utilities – Absorbed Customer Migration Risk:** More than 15% of the State’s load had migrated to contracts with competitive suppliers in the two years following retail access in May 1998. However, as high market prices in 2000 and 2001 **cost these suppliers hundreds of millions of dollars**, these providers elected to pursue a strategy of returning their customers to the utilities. This left the utilities having to shoulder the cost of purchasing energy at extremely high prices in order to serve this load.

II. RISKS OF ACCEPTING THE INDEPENDENT CONSULTANT’S RECOMMENDATIONS

In its proposed RFP and term sheet, Delmarva used great care in creating a coherent package of company and customer protections that provide balance for the substantial commitment presented by the PPA. The changes to individual terms as proposed by the Independent Consultant change this balance and subject Delmarva to a significant number of risks.

Risk #1: The Independent Consultant’s recommendations regarding security would leave Delmarva in a weak position in the event of counterparty default.

Accepting the Independent Consultant’s recommendations regarding construction period and operational period security would leave Delmarva vulnerable, particularly in light of the proposed relaxation of bidder eligibility requirements.

While Delmarva and the Independent Consultant are in general agreement on many of the proposed security-related terms in the PPA, the parties differ with regard to operational period security. Delmarva has proposed to require the Seller to post operational period security equal to a weekly calculation of the positive difference between the two-year forecast contract price for capacity and energy less the two-year forecast of market prices for these products. Delmarva also has requested that an affiliate of the Seller provide a guarantee of the Seller’s obligations under the PPA. The Independent Consultant recommends imposing a \$200/kW cap on Delmarva’s proposed operational period security mechanism.

Delmarva’s proposed operational period security structure provides a reasonable and appropriate mechanism for calculating operational period security in a long-term PPA. The uncapped two year security horizon is the minimum amount required to reflect Delmarva’s risk exposure to a weak counterparty credit in this situation. In the event of Seller non-performance, Delmarva’s ultimate recourse would be to replace the Seller with an alternative long-term supplier under similar commercial terms. Two years is the minimum length of time necessary to lock up an acceptable replacement power supply and in that sense, Delmarva has reasonably “capped” the Seller’s security obligations

under the PPA. Imposing an artificial cap on this mechanism breaks the link between security and the specific risk it is designed to mitigate in this contract. In addition, at \$200/kW, the cap results in only \$80 million of security to stand behind an estimated \$6.0 billion in capacity payments alone.² In addition, the requested affiliate guarantee provides some assurance that the Seller's enterprise, not just the entity for bidding purposes, will stand behind the PPA.

With regard to development period security, we understand that it has been proposed that the Seller would provide a letter of credit in support of only the termination fee, with no specific amount designated to cover delay damages aside from the replenishment of any draws on that letter of credit. We find this proposal to be deficient in that it does not account for the likelihood that any draw for delay damages is also an excellent indicator that the project is headed for termination. In short, we see delays and termination as going hand-in-hand. We therefore support Delmarva's proposal that the letter of credit should be of sufficient size to cover both the termination fee and the delay damages. Given the risks that are described in detail in this report, full security of these fees is of paramount importance in order to protect the interests of Delmarva and its customers.

The industry's experience with contracts signed under the Public Utilities Regulatory Policies Act of 1978 ("PURPA") is illustrative of the risk of entering into long-term contracts. PURPA required utilities to enter into contracts with new resources, and a great many of these contracts were signed in the 1980s and early 1990s. By the time the industry restructured in the late 1990's, many of those contracts had to be sold at a time when they had become significantly out-of-market. For example, New England Electric System was forced to provide over \$1.1 billion in support payments to USGen in order to transfer its PURPA contracts in the context of divestiture under the Massachusetts restructuring legislation.

We conclude overall that Delmarva's proposed security mechanisms, including an affiliate guarantee and with no imposed cap on operational security, and a letter of credit to cover the full amount of the combined delay damages and termination fees, are the minimum terms necessary to align security obligations with the risks and obligations assumed by Delmarva in this PPA.

Risk #2: As a non-firm unit specific contract, a 400MW PPA is too big for Delmarva's load.

A non-firm, 400MW PPA presents Delmarva with two related risks.

First, the total capacity charge commitment alone on a 25-year, 400MW contract in PJM could easily exceed \$6 billion. This figure is nearly ten times Delmarva's entire tangible net worth. Thus, Delmarva and its customers are substantially exposed in the event of either a default under the PPA or a plant failure in the early years of the contract,

² Based on a 400MW facility.

especially if the PPA is unit specific. It should be noted that the Act calls for selection criteria based on “cost effectiveness in producing energy price stability.”³

Second, Delmarva’s current daily load profile has many hours where load is either significantly above 400MW (as high as 800MW in some summer hours) or significantly below 400MW (as low as 200MW in some winter hours). In all hours where load is above 400MW, Delmarva must purchase energy from the market at relatively high prices. In all hours where load is below 400MW, Delmarva must sell energy to the market at relatively low prices.⁴ Delmarva expects that managing load in this way will cost Delmarva millions of dollars each year.⁵ As a result of state and federal policy initiatives to restructure the electric utility sector, Delmarva has transferred its marketing and trading organization to an arms-length affiliate that cannot act on Delmarva’s behalf, which compounds this inefficiency.

Finally, the Independent Consultant’s recommended Exposure category, which would take into account unforced capacity above 200MW for purposes of bid evaluation, is irrelevant when considering the intentions of the likely bidders. NRG considers 400MW “suboptimal”, while SCS believes that the size limit should be “at least 600MW.”⁶ As it appears today, there will be few bidders who will bid a project size approximating the needs of Delmarva and its customers unless bidders are specifically limited to fulfilling those needs and no more.

Risk #3: The proposed contract structure subjects customers to high market risk over its 25-year term without sufficient offsetting SOS customer protection.

Electricity prices tend to follow trends that can cause significant deviations over the long term. PJM’s annual average LMP price has more than doubled since 1998.⁷ It is not difficult to infer the large degree to which this market price could deviate from the energy price in the PPA over the course of 25 years, regardless of any indexing that may be a part of the contract. It is then not unreasonable to assume that since Delaware’s restructuring legislation provides for customer choice, there is the risk of substantial customer migration in scenarios where the market price falls below the contract price.

Delaware is a customer choice state. Nineteen competitive suppliers are currently registered in the State to compete against the incumbent utility to sell power to retail customers. Following the conclusion of Delmarva’s POLR obligation in May 2006, SOS (“Standard Offer Service”) service rates are in the process of moving up to reflect competitive market prices. As a result, while Delmarva had lost only 4.1% of its distribution load obligation to competitive suppliers by December 2005, this loss has

³ Electric Utility Retail Customer Supply Act of 2006, p. 6.

⁴ This risk is discussed in detail in Delmarva Power & Light Company’s Comments on the Independent Consultant’s Report, as filed September 18, 2006, pp. 8-11.

⁵ “Delmarva Power & Light Company’s Comments on the Independent Consultant’s Report,” September 18, 2006, p. 10.

⁶ “Issue Sheets with Various Parties’ Positions,” October 13, 2006, p. 4.

⁷ Source: PJM “2005 State of the Market Report,” Table 2-32. CEA calculation.

increased to 33.2% of the Company's distribution load obligation by September 2006.⁸ This is the result of SOS rates moving to *parity* with market prices. Under the pending RFP for New Generation Resources, a portion of SOS supply may not fully reflect market prices in the future. Given the migration that has occurred in 2006 as a result of parity between SOS and market rates, one can infer a significant increase in migration above this level in the event market prices were to fall below the SOS rate. The Independent Consultant report concedes:

*"There is a risk that a stable-priced contract with a generator could become substantially over-market during the 2012-2037 contract period ... If that were to occur in a sufficiently substantial magnitude, customers might leave SOS for the competitive market leaving fewer customers to bear higher unit over-market costs."*⁹

The above statement illustrates the beginnings of a vicious cycle, with each customer departure creating stranded costs that are then passed on to remaining customers, further widening the gulf between the SOS price and market prices. If market prices continue to fall or at least remain below the SOS price, the inevitable result is that too few customers will be left to pay for the fixed portion of the SOS cost, which in turn could result in Delmarva's default under its supply contract.

The Independent Consultant argues that any tide of customer migration can be stemmed through legislative fiat by cancelling customers' ability to shop, and states correctly that this step was required in California in order to restore order to that market. However, the California situation was an emergency measure that could have been avoided if California's POLR contracts had better reflected market prices to begin with and served to undermine the California Legislature's goal of open access. The Delaware Commission has an opportunity today to properly structure customer protections and freedoms such that there is never a need to fear customer migration at crisis levels.

Risk #4: There is a high risk of default if non-investment grade entities are permitted to bid.

There is an unacceptably high likelihood of default by a non-investment-grade entity over a 25-year period. According to Moody's, the cumulative risk of bond default during a twenty-year period by a Ba-rated entity (highest non-investment-grade rating) is approximately 30%. By point of comparison, there is only a 13% risk of default over 20 years for a Baa-rated entity (lowest investment-grade rating).

If the investment term is limited to ten years, the Baa and Ba probabilities of default are 8% and 19%, respectively. While this risk is more palatable than the 20-year term, it highlights the substantial increase in the chance of default when contracting with a non-investment-grade entity, regardless of contract term.

⁸ Source: Delmarva Light & Power Company. CEA calculation.

⁹ "Final Report Regarding Delmarva Power & Light Company's Proposed RFP," October 12, 2006, p. 10.

In Delmarva's case, a PPA counterparty default would result in Delmarva having to re-contract for power on potentially less favorable terms. In addition, Delmarva's liquidity would become constrained, with the possibility of facing a downgrade to non-investment grade.

It is also important to keep in mind that this PPA is not intended to provide the bidders with an outlet for their power. PJM already provides this outlet, and stands ready to purchase every MWh that the unit produces at the full market value of that power. Rather, the PPA is primarily a vehicle for the bidder to use the financial strength of Delmarva to provide the project with credit support so that financial leverage can be used to enhance the project sponsor's return. In this way, the PPA relationship is parasitic, as it also limits Delmarva's financial flexibility in the process.

Risk #5: Bids are likely to include new higher-risk technologies, increasing the risk of counterparty default due to technical failure.

The bids submitted in response to Delmarva's RFP are likely to include new higher-risk technologies, which will increase the risk of counterparty default. For example, NRG has specifically proposed the construction of an Integrated Gasification Combined Cycle ("IGCC") unit. If accepted and built, this project would be the first non-utility IGCC. Previously constructed IGCCs have had an inconsistent track record with regard to efficiency and availability. For example, the lackluster availability demonstrated during the first several years of the operation of the Wabash River Coal Gasification Repowering Project is a major cause for concern to all potential IGCC stakeholders.¹⁰ The following table illustrates the operating problems during this plant's Demonstration Period.

Operation of the Wabash River IGCC Plant During Demonstration Period ¹¹		
Year	Availability Factor	Operating problems
1996	22%	<ul style="list-style-type: none"> Frequent failure of the ceramic filter elements in the particulate removal system Ash deposits in the post gasifier pipe spool and HTHRU
1997	44%	
1998	60%	<ul style="list-style-type: none"> Ten coal interruptions and other periods of downtime were caused by air separation unit (ASU) Plant suffered downtime while processing different coal feedstocks
1999	40%	<ul style="list-style-type: none"> Failure of a blade in the compressor section of the combustion turbine required complete rotor rebuild that idled Project for 100 days Syngas leak in the piping system of particulate removal system Failure of a ceramic test filter in the particulate removal system

¹⁰ Wabash River Coal Gasification Repowering Project, Final Technical Report for U.S. Department of Energy, by Wabash River, Ltd., August 2000, p. 4-2.

¹¹ Wabash River Coal Gasification Repowering Project, Final Technical Report for U.S. Department of Energy, by Wabash River, Ltd., August 2000, p. 4-2.

Other bidders have proposed wind power facilities, which have yet to be fully accepted as mainstream generation sources. FERC notes: “Even with the advances in wind development, wind generation is a relatively new entrant to markets that were not designed specifically for intermittent energy sources or for energy sited remotely from load centers. As such, wind generation faces several challenges to achieve widespread acceptance, including siting and permitting issues, financing issues and transmission policies that are currently designed for generating units that are more centrally located and that are able to be dispatched.”¹²

Higher levels of technological risk impose a higher risk of contract counterparty default than more mainstream technologies, and therefore require higher levels of security. Delmarva take on the development and operating risk of these higher risk technologies to the extent that any capacity payment bid is accepted as part of the RFP.

Risk #6: Bids are likely to be structured with a high capacity component, increasing market risk.

Newer technologies such as wind power and IGCC have higher capital costs and lower capacity factors than most conventional technologies. As a result, bidders will likely structure higher capacity payments in their bids in order to best match their own cash flow. However, a high capacity price payment structure imposes risk on Delmarva, which is obligated to take-or-pay the capacity portion of the bid, regardless of load. As a result, Delmarva’s PPA revenue may fall below the contract cost if load were to stagnate or migrate.

Risk #7: Bids will likely be front-end loaded, also contributing to market risk.

Many bidders will structure their payment streams with higher payments in the near-term in order to enhance their ability to attract financing. Since bids will be evaluated on a levelized basis, there would be no bidding disadvantage to such a front-loaded structure. This structure allows the seller of energy and capacity under the proposed PPA (the “Seller”) to take large up-front payments, without strong security terms, would leave Delmarva the risk of never getting to the “good” years.

Historically, it was not uncommon to find “energy bank” or “advance payment account” provisions in such front-end loaded PPAs. The energy bank required sellers to pledge early-year above-market PPA payments as collateral to securitize out-year benefits to the buyer in the form of below market contract payments. Credit and security mechanisms appropriate to front-end loaded PPA payment structures should certainly be accommodated in this RFP process.

¹² “Assessing the State of Wind Energy in Wholesale Electric Markets,” Federal Energy Regulatory Commission. Docket No. AD04-13-000, Staff Briefing Paper, November 2004, p. 16.

III. RISKS OF THE PROPOSED PPA ARE PARTICULARLY ACUTE GIVEN DELMARVA'S SITUATION

Delmarva's concerns regarding potential risk exposure arising from the Independent Consultant's revisions to the proposed RFP do not arise out of some theoretical or "worst case" risk assessment exercise. Rather, Delmarva's concerns reflect a practical assessment of its current financial condition and regulatory environment. The following key factors underlie Delmarva's response to the Independent Consultant's proposed revisions:

Financial Condition. As noted above, CEA estimates that **a 25 year, 400 MW PPA could impose approximately \$6.0 billion of future capacity payments on Delmarva's customers.** To put this burden in perspective, Delmarva's balance sheet reports a current net worth of under \$650 million. Delmarva's financial condition therefore offers scant capacity for absorbing incremental debt or debt-like instruments. The financial market recognizes this limitation; Delmarva's current senior unsecured credit ratings are BBB-/Baa2 (S&P/Moody's). The financial community understands that the Company has modest capability for absorbing fixed cost obligations of the magnitude inherent in the Independent Consultant's proposed PPA revisions without triggering credit quality concerns. Delmarva's credit degradation risk is exacerbated to the extent the RFP is revised to allow for under or poorly securitized counterparty credit to backstop PPA performance obligations.

Contestable Market. Delaware has fully opened its retail market to competition, granting all of Delmarva's customers the ability to switch from standard offer service to alternative power suppliers if the Company's power supply costs are non-competitive. Compounding the risk attendant with full retail access is the demonstrated liquidity of the PJM wholesale market, which ensures that alternative suppliers can readily structure flexible and market-responsive power supply portfolios to compete with Delmarva's standard offer service. Full market contestability makes it critically important for Delmarva to align its supply resources to its load obligations. Hence, supply flexibility and market responsiveness are vitally important power supply objectives.

While it is beneficial to receive a broad spectrum of bids, it is also critical to be mindful of Delmarva's proposed project size when evaluating these bids. Delmarva proposed a PPA size of 200 MW in order to minimize the risk that it would be obligated to buy excess baseload energy at a contract price that differed from the spot market price. Secondly, the 200 MW size limit provided Delmarva with headroom to procure other baseload resources and achieve some degree of resource diversity in its supply portfolio. Lastly, Delmarva's requirement that the Seller deliver firm energy shielded its customers from generating unit availability risk and the exposure to volatile replacement power costs. In contrast, accepting a larger project size would obligate Delmarva to buy more of a less valuable baseload resource than is warranted by a prudent consideration of load obligations and supply portfolio objectives. Accepting a bid to contract for more than 200 MW of baseload

power on a unit contingent basis for 25 years poses the very real risk of triggering a declining load/rising per unit cost “death spiral” scenario.

Corporate Structure. As a result of state and federal level policy initiatives to restructure the electric utility sector, Delmarva has divested its generation resources, transferred its power marketing capabilities to an arms-length, unregulated affiliate, and now procures 100% of the power supply it requires to serve its remaining load obligations pursuant to a state mandated standard offer service procurement regime. **As such, Delmarva lacks the corporate capability to manage a long-term inflexible purchase commitment in a competitive wholesale market environment with contestable retail markets. In particular, the Independent Consultant’s proposed PPA revisions may force the Company to acquire additional resources (either internal or external) to manage both excess energy and replacement energy risks throughout the term of the PPA.** In addition, a large project size will likely leave Delmarva a smaller and less attractive market for competitive wholesale providers of load following service. Overall, a large project size is a poor strategic fit with Delmarva’s existing corporate capabilities and can be expected to increase Delmarva’s costs for supplying standard offer service.

Combined, these factors indicate that Delmarva has insufficient financial strength and strategic ability to manage a large, inflexible power supply obligation without adequate security. The practical implications of the Commission’s decision to expose Delmarva to market and financial risks of the magnitude proposed by the Independent Consultant will be to degrade Delmarva’s credit quality and increase its cost of capital.

IV. THESE RISKS ARE REAL

There are many examples of lessons learned by electric utilities across the United States demonstrating the inherent risk associated with large, long term contracts, including above market costs in long term contracts, counterparty credit risk, the risk of falling below investment grade, liquidity risk, customer migration and project default. The past 15 years have provided numerous examples where regulatory commissions and/or state legislatures have directed utilities to enter into PPAs, the regulators have approved the PPAs, and the utility and its customers have suffered significant financial harm from those PPAs.

Risk of Long Term Contracts

- **Niagara Mohawk** - In the 1990s, after suffering under out-of-market PPAs and a loss of load resulting from high system energy costs, Niagara Mohawk narrowly avoided bankruptcy as it attempted to buy out and/or restructure many of its

PPAs with Independent Power Producers ("IPPs").¹³ After years of litigation, Niagara Mohawk reached a Master Restructuring Agreement to terminate PPAs totaling 1,092 MW and to buy-down the terms of another 535 MW of IPP capacity. The aggregate cost to Niagara Mohawk was a payment of \$3.9 billion in cash and an issuance of 20.5 million shares of common stock to the IPPs.

- **NStar** - Massachusetts also encouraged its utilities to sign contracts with IPPs and QFs in the late 1980s and early 1990s to promote competition for new generating resources. These policies led to numerous out-of-market PPAs by the late 1990s. NStar negotiated a buyout of 685 MW of out-of-market PPAs for which the present value of the stream of buy-down payments for the PPAs was \$1.4 billion dollars.
- **New England Electric Systems ("NEES")** - In 1998, NEES agreed to sell its non-nuclear generating assets to USGen. This transaction included 1100MW of New England Power's out-of-market purchase power agreements.¹⁴ NEES agreed to provide support payments in the amount of \$1.17 billion for the above market cost of these contracts through 2008.¹⁵
- **California Department of Water Resources ("CDWR")** - In response to the perceived power supply shortages experienced in California and the corresponding skyrocketing energy prices, in 2001, the CDWR negotiated long term power agreements with merchant generators to meet the energy needs of California consumers at a cost of \$42 billion.¹⁶ The majority of the contracts are take or pay contracts in which the CDWR guaranteed payment for the contractual quantities whether or not the energy was needed to meet demand. While the CDWR renegotiated many of these contracts due to evidence of market manipulation, reducing the cost of the agreements by \$11 billion, estimates are that California will still be required to pay nearly \$10 billion in above market power supply costs related to these long term agreements, some of which extend to 2021.¹⁷

Counterparty Credit Risk

Numerous negative events caused the investment community to become extremely wary of the merchant generation and energy trading sectors, and caused creditors to regard these businesses as much riskier than they had previously. The following examples illustrate the effect of counterparty credit on the industry:

¹³ The out-of-market PPAs had been executed under New York's "six-cent law," which required utilities to pay a floor price of \$0.06/kWh for qualifying facilities less than 80 MW. Although the law was repealed in 1992, it did not retroactively apply to existing PPAs.

¹⁴ Subsidiary of NEES.

¹⁵ New England Electric System, 1998 10-K-405.

¹⁶ "DWR Keeps Power Flowing During Unprecedented Energy Crisis," California Energy Resources Scheduling.

¹⁷ "The California Electric Crisis," Sweeney, James L, April 9, 2002, p. 305.

- **Enron** - At the time of Enron's bankruptcy filing, the aggregate exposure to Enron of all its counterparties was estimated at \$6.3 billion.¹⁸ Energy companies held \$900 million of that exposure, and the top 10 most exposed publicly traded energy counterparties held a combined total of \$685 million.^{19,20} The effect on the market capitalization of this top 10 group was immediately quantifiable. The day after Enron's filing, the market capitalization of these firms had declined by \$4.2 billion.²¹
- **PEPCO** - In the sale of PEPCO's generation assets to Southern, PEPCO retained responsibility as a purchaser under two PPAs and entered into a back-to-back arrangement with Southern for these agreements. Subsequently, in 2003, when Southern's successor, Mirant, filed for bankruptcy, Mirant estimated that the PPAs were out of market by up to \$895 million through 2021 and sought to unwind the back-to-back contracts.²² Through a settlement agreement pending court approval, Mirant will be allowed to terminate the back-to-back arrangement and PEPCO will be responsible for any further risks under the contract which expires in 2021.²³
- **Connecticut Light and Power Company ("CL&P")** - Due to concerns of the potential for NRG Power Marketing ("NRG-PM") to default on its CL&P SOS obligations, which would result in increased purchased power costs to CL&P, Fitch Ratings lowered its ratings outlook on CL&P to negative in February 2003. As predicted, in May 2003 NRG-PM's parent, NRG Energy ("NRG") filed for bankruptcy and NRG-PM attempted to terminate its SOS obligations to CL&P. For almost three weeks in the summer of 2003, NRG-PM stopped serving CL&P's SOS load, forcing CL&P to procure supplies at a net cost of \$8.5 million to ensure customers continued to receive power.^{24,25}
- **United Illuminating** - As a result of Enron's bankruptcy, United Illuminating (UI) cancelled a contract with Enron for supplies to cover its 1200 MW standard offer load.²⁶ Enron's bankruptcy filing triggered UI's right to terminate the agreement and UI exercised this right. While Enron never defaulted on the

¹⁸ "Companies' Enron exposure estimated at \$6.3 bln," Reuters News Service, December 7, 2001.

¹⁹ Ibid.

²⁰ The top ten companies included New Power Holdings, Duke Energy, The Williams Companies, Inc, Reliant Energy, Inc. Dynegy, Inc., Aquila/Utilicorp United, Mirant Corporation, American Electric Power, El Paso Corporation, and ONEOK, Inc.

²¹ ERisk, "Potential Exposure- How To Get A Handle on Your Credit," *Jim Rich and Curtis Tange*.

²² Platts Power Markets Week, "Mirant Says it Could Lose \$340 Million by 2005 if it Can't Leave PEPCO Power Deal," November 17, 2003.

²³ PEPCO will receive \$450 million as compensation to take on the above-mentioned contract.

²⁴ The FERC and the District Court ordered NRG-PM to resume service. Under a settlement agreement approved in late 2003, NRG was required to honor the SOS contract through the end of its term and CL&P was refunded the \$8.5 million.

²⁵ CL&P 2002 10-k and CL&P 2003 Annual Report.

²⁶ In 1999 UI contracted with Enron to supply its entire standard offer load for the full transition period from January 2000 through December 2003.

contract, ultimately UI chose Dominion Energy to supply its standard offer load at the existing rates for 2002 and 2003.²⁷

Customer Migration Risk

In addition to price and liquidity risk, in states where retail access is available to all customers, utilities are exposed to significant risk associated with customer migration. For example, in 1996 California implemented full retail choice for all customers. By May 2000, California utilities had seen more than 15% of the state's load migrate to direct access contracts, mostly through large industrial customers.²⁸

However, in 2000 and 2001 California's energy market saw unprecedented price increases, reaching monthly average levels of more than \$100/MWh by June 2000. By year-end 2000, wholesale power prices averaged approximately \$250/MWh, the state's electric utilities were on the verge of bankruptcy because of their inability to pass these higher costs onto customers, and the state was facing the very real prospect of extended blackouts because generators were concerned that they might not be paid for the power they produced and sold to the state's utilities.

It was during this time frame that California's competitive providers faced losses from their contracts with Direct Access customers of hundreds of millions of dollars. As a result, certain competitive providers chose to return their Direct Access customers to the utilities' bundled service, which had the effect of worsening the financial distress of the utilities. The California utilities that Enron returned to bundled service have estimated that, for their loads alone, the State faced \$12 million per month of extra costs for purchased power. PG&E and SCE, which still had capped rates in place for bundled service, were required to take these customers back onto bundled service, even though it meant that they would be selling power to these customers at a very large loss. By April 2001, only 2% of the load in California was being served by competitive providers, requiring utilities to take on the responsibility to purchase power for the additional load.²⁹

Default

The liquidity crisis was exacerbated by the unprecedented level of power plant construction that was financed with short-term construction or so-called 'mini-perm' financings. The traditional use of long-term project financing for unregulated generation evolved into short-term mini-perm bank loans of up to five years with expected bond takeouts.³⁰ Facing large, near term maturities, many merchant companies could not meet

²⁷ Platts Electric Utility Week, "UI Picks Dominion for Standard Offer Load After Nixing Contract with Enron," January 14, 2002.

²⁸ California Public Utilities Commission, "Supplemental Direct Access Implementation Activities Report Statewide Summary," June 15, 2000.

²⁹ California Public Utilities Commission, "Supplemental Direct Access Implementation Activities Report Statewide Summary," May 15, 2001.

³⁰ Spangler, A. et al. "Credit & liquidity; credit crunch and liquidity in energy," Power Economics, October 31, 2002.

these large short-term debt payments and therefore attempted to refinance. Many companies found that their efforts to refinance were stifled when the ratio of common equity to total capitalization dropped below the minimum required by the SEC.³¹ Several companies including Mirant, NRG, PG&E's National Energy Group, and Calpine, filed for Chapter 11 bankruptcy protection.

- **Mirant Corp.** - Between October 2002 and June 2003, S&P issued a series of downgrades that lowered Mirant's corporate credit rating from BBB- to CCC, citing depressed power prices, high leverage, and insufficient cash reserves to meet its debt obligations over the following two years.³² Prior to this period, Mirant had taken steps to increase liquidity by divesting assets, delaying or cancelling new projects, and issuing equity-like securities.^{33,34,35} Despite efforts to refinance, Mirant filed for Chapter 11 bankruptcy protection in July 2003. In bankruptcy, Mirant attempted to reject a back-to-back agreement with PEPCO including certain PPAs. A U.S. appeals court ultimately rejected Mirant's effort to terminate the back-to-back agreement; however, Mirant and PEPCO entered into a settlement agreement before the decision was rendered.^{36,37} In addition, Mirant terminated a 20-year tolling agreement with Perryville Energy, forcing Perryville to default on project loans.³⁸
- **NRG** - Between July and August 2002, S&P downgraded NRG's corporate credit rating from BBB- to CCC, citing that "NRG's liquidity position is severely constrained and even if the banks continue to waive the collateral requirements under the \$2 billion construction revolver, NRG could be challenged to meet debt service requirements without significant asset sales."³⁹ To mitigate the liquidity crisis, NRG pulled out of the 1,168 MW Pike project after it was 20% built, leaving more than \$100 million behind.⁴⁰ Despite efforts to refinance debt, NRG filed for Chapter 11 bankruptcy protection in June 2003. Later that year, NRG surrendered 633 MW in generating assets to lender ABN AMRO.⁴¹ In addition, NRG moved to reject its power supply agreement with Connecticut Light and Power. The parties eventually settled the dispute in late 2003.⁴²

³¹ "Company results; bankruptcy fells Mirant," Power Economics, August 26, 2003.

³² SNL Energy

³³ Rigby, Peter. "Is time running out for energy merchant companies," Platts Energy Business & Technology, October 2002, Vol. 4, No. 6, p. 13.

³⁴ Ibid.

³⁵ Ibid.

³⁶ Zink, N.T. and S.R. Rivera, "Court rejects attempt to cancel contract in bankruptcy," Monday Business Briefing, September 22, 2006.

³⁷ Moore, J. and S. Watts, "Regulatory and legal developments continue to shape US markets," Project Finance, October 1, 2004.

³⁸ Foster Electric Report, "Potential Sale of CLECO plant to Entergy may spark another controversy over a plant being taken out of the market by an integrated utility; EEI fights back," February 4, 2004.

³⁹ SNL Energy

⁴⁰ Burr, M. "Deal of the 21st Century?," Public Utilities Fortnightly, March 15, 2003.

⁴¹ Burr, M. "Power flux; generators struggle to plan for the future as they cope with an unstable present." Public Utilities Fortnightly, December 2003.

⁴² Moore, J. and S. Watts. Regulatory and legal developments continue to shape US markets. Project Finance, October 1, 2004.

- **PG&E** - The burden of substantial short-term debt payments pushed PG&E National Energy Group (“NEG”), a merchant subsidiary of PG&E Corp., into a liquidity crisis and ultimately bankruptcy in 2003. Between October and November 2002, S&P lowered NEG’s corporate credit rating from BB+ to D, citing NEG’s weak operating performance, tight liquidity, and the default on debt payments.⁴³ By July 2003, NEG had reduced the aggregate value of its energy-trading portfolio by more than 70%.⁴⁴ NEG also renegotiated short-term credit facilities, obtaining extension from its bank in spring 2003.⁴⁵ Despite these measures, PG&E NEG filed for Chapter 11 bankruptcy protection in July 2003. PG&E-NEG defaulted on six plants including La Paloma (1022 MW in Kern County, CA) and Lake Road (792 MW in Killingly, CT) which were turned over to Citibank in July 2004. Equity in the Millennium Power facility (360 MW, Charlton, MA), the Harquahala facility (1175 MW, Tonopah, AZ), the Covert Plant (1200 MW, Covert, Mich.) and the Athens Plants (1080 MW, Athens, NY) were transferred to a syndicate headed by Societe General in March 2004.⁴⁶
- **Attala Generating Company, LLC (“Attala Generating”)** - In 2003 Attala Energy Company LLC (Attala Energy), a wholly owned subsidiary of PG&E-NEG, completed a \$340 million sale and leaseback transaction on its 526 MW generating facility. Under the agreement, Attala Energy entered into a 25-year tolling agreement with Attala Generating with sufficient cash flows to make payments under Attala Generating’s lease agreement. Attala Energy defaulted on payments under the tolling agreement and PG&E-NEG, who provided a guarantee to support Attala Energy’s payment obligations, defaulted on payments under its corporate revolver, resulting in a termination of the tolling agreement. Under the terms of the lease agreement, termination of the tolling agreement, if not replaced within a predetermined period of time, triggered termination of the lease and foreclosure of the assets securing the lease. The tolling agreement was not replaced and in 2003, the FERC authorized the acquisition, by foreclosure of the 526 MW Attala generating facility by its lenders from PG&E’s subsidiary, Attala Generating.⁴⁷
- **Calpine** - Rapid expansion from 2001 through 2004 to a 26,000 MW company was funded primarily by incurring additional debt. Obligations to service this debt, coupled with challenging market conditions for electricity providers caused the company to file for Chapter 11 in December 2005. As part of this filing, Calpine filed a motion with the U.S. Bankruptcy Court to reject eight PPAs with California DWR, PG&E, Southern California Edison, and Acadia Power Partners. Under most of the PPAs sought to be rejected, Calpine was obligated to sell power at prices that were significantly lower than currently prevailing market prices. The Court determined that the issue of performance under the

⁴³ SNL Energy

⁴⁴ Third merchant bites the dust: PG&E unit files for bankruptcy in Natural Gas Week, July 13, 2003.

⁴⁵ S&P says that the recent debt refinancings of several merchant energy companies may hamper their long-term financial recovery in Foster Electric Report, April 30, 2003.

⁴⁶ Power Markets Week, “Boutique Management Firms Purchase Power Assets held by Banks for Non-Payment of Debt,” May 23, 2005.

⁴⁷ PG&E Corporation 2002 Annual Report, p.16.

agreements was FERC jurisdictional. No final ruling has been made at this time.⁴⁸

- **Allegheny Energy Supply (“Allegheny”)** – In 2001-2003, Allegheny suffered the effects of wholesale energy market conditions across several of its projects. By the second quarter of 2002, Allegheny announced the write-down and/or cancellation of several projects it had undertaken since 2000. Furthermore, Allegheny announced in its second quarter SEC Form 10-Q that it was canceling 1,080 megawatts of generation planned for La Paz, Arizona and 88 megawatts of combustion turbine generation planned for St. Joseph, Indiana.⁴⁹

Between August 2002 and May 2003, S&P lowered the corporate credit rating of Allegheny and its subsidiaries from BBB+ to B, citing increasing leverage and worse-than-expected weakness in the wholesale power market.⁵⁰ In October 2002, the parent company defaulted on its credit lines at its subsidiary, refusing to post additional collateral for trading activities.⁵¹ Allegheny Energy avoided bankruptcy by refinancing its bank loans, resulting in an upgrade by S&P from “negative” to “stable” in February 2004.⁵²

In addition to the number of generation projects that were cancelled as a result of credit and liquidity issues, many existing plants or plants in later stages of construction were turned over to lending groups as a result of defaults on project loans. Through mid-2005, the default on debts by the following generating firms, or their affiliates, put at least 9,500 MW of capacity into the hands of bank lending groups:

- **El Paso** defaulted on project loans related to Milford Power (544 MW), located in Connecticut, as a result of project delays due to a fatal construction accident and a lengthy legal dispute. The plant was transferred to a lender group led by Belgian-based KBC Bank in December 2003 before the plant came on-line.⁵³
- **Boston Generating**, a former Exelon subsidiary turned control over to a syndicate of bankers led by BNP Paribas after it defaulted on a \$1.25 billion credit facility in August 2003. In September 2004, Boston Generating transferred to its lenders 3400 MW of capacity, including the Mystic and Fore River plants.⁵⁴
- **Reliant Energy’s** Liberty Electric (530 MW) located in Pennsylvania was foreclosed upon by a lending group led by JP Morgan in August 2004 after it defaulted on its \$242 million project financing. NEG had a 14-year contract to

⁴⁸ Since the Court ruling on jurisdiction in January 2006, three of the PPAs have been terminated by the applicable counterparties, and two of the PPAs are the subject of negotiated settlements. Calpine continues to perform under the three PPAs that remain in effect.

⁴⁹ Id.

⁵⁰ SNL Energy

⁵¹ Moore, J.R. and S.H. Watts, “Regulatory and legal developments continue to shape US markets,” Project Finance, October 1, 2004.

⁵² SNL Energy

⁵³ Global Power Report, “Troubled Milford 544-MW Plant in Conn. Ready for Operation After Three-Year Delay,” January 29, 2004.

⁵⁴ Power Markets Week, “Recycling Merchant Megawatts: Banks Hire Their Brethren to Find Buyers for 10,000 MW,” August 23, 2004.

purchase the plant's output, but the contract was terminated in NEG's bankruptcy proceeding, leaving Liberty to sell into the merchant market.⁵⁵

- **TECO Energy** transferred ownership of Gila River (2145 MW) in Arizona and Union (2200 MW) in Arkansas to Entegra, whose 35 members had lent money to the projects after TECO defaulted on \$2.2 billion of loans. The transfer occurred in May 2005.^{56,57}
- **AES Corp** transferred Granite Ridge (720 MW) in New Hampshire to a creditor group led by ABN Amro in November 2004. Granite Ridge experienced startup problems in 2003 and was involved in a tax dispute. AES decided to transfer the plant to creditors after it was unsuccessful in selling the plant.^{58,59}

V. RFP ISSUES CURRENTLY BEFORE THE COMMISSION

There are three primary open issues before the Commission on which we comment below.

- 1) The proper terms regarding operational security requirements;
- 2) The proper percentage of imputed debt to apply to bids under evaluation; and
- 3) Whether to permit cancellation of the PPA in the event the Seller is deemed to be a Variable Interest Entity at any time during the PPA term.

Operational Security Requirements

As part of its Operational Security requirements, Delmarva has proposed that the Seller post collateral for the mark-to-market dollar amount by which the value of the two upcoming years of energy and capacity values in the market exceed the energy and capacity costs under the PPA for those two years, as calculated on a weekly basis. This two year period provides a *minimum* time period to seek replacement power.

In contrast, the proposed \$200/kW limitation on operational security is both redundant and restrictively low. It is redundant in that the two-year time period already acts effectively as a cap on the required security commitment by limiting the time period for which the weekly mark-to-market calculation is made. It is restrictively low in that it represents only \$80 million on a 400MW facility, relative to an expected \$240 million.⁶⁰ *annual* commitment for fixed cost payments alone for an IGCC facility of that size. On this basis it would make no allowance for the purchase of replacement energy at market prices that are above the contract price.

⁵⁵ Megawatt Daily, "Lenders Foreclose Reliant's Liberty Plant," August 30, 2004.

⁵⁶ Global Power Report, "Banks hold 14,065 MW of Merchant Assets as a Result of Defaults by Four Companies," February 19, 2004.

⁵⁷ Megawatt Daily, "Entegra Power Searching for More Assets," June 6, 2005.

⁵⁸ Global Power Report, "Unable to Sell Plant, AES Corp. Begins transfer of 720-MW N.H. Plant to Creditors," June 3, 2004.

⁵⁹ AES Corp. 2004 10-K.

⁶⁰ Required annual payment over 25 years for the \$6.0 billion total commitment described in Footnote 1.

Finally, as shown in JJR-2, there is ample evidence from other RFPs that the norm is to not impose a cap on operational security.

For these reasons, it is both unnecessary and unreasonably burdensome to impose a \$200/kW cap on operational security.

Imputed Debt Offset

The concept of imputed debt has risen to prominence largely as a result of the increased use of off-balance-sheet financing. Although the use of off-balance sheet leases has declined, rating agencies have continued to focus on the long-term obligations of creditors that are largely debt-like in character, including PPAs. In general, Standard & Poors “applies a 0 to 100% risk factor to the net present value of the PPA capacity payments, and designates this amount as the debt equivalent.”⁶¹ The actual percentage applied depends on how much the capacity payment commitment resembles the credit risk characteristics of long-term debt. Standard & Poors sets a *minimum* imputation rate of 30% for “utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased power costs.”⁶²

This 30% should be interpreted as a *baseline* multiplier, applicable only to utilities with a diversified supply portfolio. Higher percentages are applied when the contract has a long term, is tied to an individual seller, is a “take-or-pay” commitment that is not tied to performance of the unit, and/or is out-of-market.^{63,64} In addition, S&P warns that “if a utility relies on any individual Seller for a material portion of its energy needs, the risk of non-delivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.”⁶⁵ Delmarva will rely heavily on an individual seller under its RFP, and non-delivery risk is very real.

In fact, the proposed PPA may have all of the attributes discussed above. It will likely have a long term (10-25 years), it will be tied to an individual seller and will therefore have non-delivery risk, it has attributes of a take-or-pay commitment to the extent that a capacity component is bid, and it will likely be priced above market in the initial years for reasons discussed in Section II. Moreover, other RFPs in the market have used a 50% risk factor, as shown in Exhibit JJR-1. For these reasons, a 50% risk factor is consistent with S&P and Moody’s guidelines and is fully warranted.

Assuming \$6.0 billion in capacity payments as noted above, and a 50% risk factor is used, an imputed debt value of over \$1.25 billion would be effectively added to

⁶¹ “Buy Versus Build”: Debt Aspects of Purchased-Power Agreements,” p. 1.

⁶² “Buy Versus Build,” op. cit., p.2.

⁶³ Ibid.

⁶⁴ Direct Testimony of George E. Tyson, In the Matter of a Petition by Excelsior Energy Inc. for Approval of a Power Purchase Agreement Under Minnesota Stat §216B,1694, Minnesota Public Utilities Commission, Docket No. E6472, p. 19.

⁶⁵ “Buy Versus Build,” op. cit., p. 2.

Delmarva's debt in its future credit reviews.⁶⁶ This commitment dwarfs the \$516 million in total long-term debt currently on Delmarva's balance sheet, and would create total debt at Delmarva of more than \$1.7 billion.⁶⁷ As a result, the interest and debt service coverage ratios used as key credit metrics by the rating agencies would be approximately cut by two-thirds. Absent a large infusion of equity (and perhaps even with such an infusion) this would cause a significant deterioration in Delmarva's credit rating, especially given Delmarva's current precarious credit standing. In turn, the jeopardized credit rating would put upward pressure on Delmarva's cost of debt and access to capital. For the reasons discussed above, Delmarva is fully justified in using *at least* a 50% imputed debt offset in the price factor of its bid evaluations.

Variable Interest Entity Treatment

As Delmarva indicated in its proposed RFP, with respect to non-affiliated third-party bids, it "is unwilling to be subject to accounting and tax treatment that results from Variable Interest Entity treatment as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 (revised December 2003) as issued and amended from time to time by FASB."⁶⁸ Delmarva further instructed bidders to provide all the information necessary to make such an assessment. The bidder instructions indicated that "such information may include, but is not limited to, data supporting the economic life, the fair market value, executory costs, non-executory costs, and investment tax credits or other costs (including debt specific to the asset being proposed) associated with the bidder's proposal".⁶⁹

FIN 46 requires the consolidation of entities over which control is achieved through means other than voting rights; such entities are known as variable interest entities ("VIEs"). This poses financial uncertainty and significant risk to power purchasers as it requires the capitalization of the VIE assets and liabilities on the books of the consolidating company, for which it has no control other than contractual. Moreover, depending upon the capitalization of the VIE, the potential increased leverage could substantially affect financial metrics of Delmarva, posing an unacceptable risk for a Company whose senior unsecured debt is on the margin of investment grade.

The determination of whether an entity may have to apply the provisions of FIN 46 and consolidate a VIE, hinges upon the following primary criteria.⁷⁰ A VIE exists, if by design:

⁶⁶ Calculated as 50% of the present value of level capacity payments over 25 years using the estimated cost of debt for Delmarva.

⁶⁷ 10-K of PEPCO Holdings, Inc., for FYE December 13, 2005.

⁶⁸ Delmarva Power & Light company Request for Proposals, Instructions to Bidders, Part 2.2.2, at 7.

⁶⁹ Ibid.

⁷⁰ If it is determined that a VIE exists, a second criterion, requiring a determination of whether Delmarva could be considered a primary beneficiary is applied. A primary beneficiary is designated as an entity that would absorb a majority of the VIE's expected losses or receive a majority of the VIE's expected returns. If it is determined that a primary beneficiary exists for a VIE, it is presumed to have financial control of the VIE and therefore, consolidation is required. On the other hand, if a VIE's risks or rewards are spread among various unrelated parties, and no one unrelated party absorbs a majority of the VIE's losses or receives a majority of the returns, consolidation is not required.

- 1) The total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, or
- 2) The entity lacks one of the characteristics of a controlling financial interest, or
- 3) One or more of the equity investors have voting rights not proportionate to their obligations to absorb expected losses or receive residual returns of the entity.

A PPA may be subject to FIN 46, regardless of ownership, voting interests, or investment, if it transfers virtually all risks to a primary beneficiary, i.e. the contract holder or buyer. Such transfer of risks might include: risks of construction, commodity prices, operations, environmental regulation and costs, financing and others. Any instance of a seller receiving a full or partial guarantee of cost recovery through a purchased power contract virtually transfers all risk from the seller to the buyer, and virtually guarantees that consolidation will be required under FIN 46.

As noted in the Commissions Initial Independent Consultant's Report, "the basis for determining whether a specific project entity or structure triggers FIN 46 is murky at best."⁷¹ In order to assess the applicability of FIN 46, respondents should provide sufficient financial information to provide a comprehensive understanding of the ownership and risk structure of the proposed agreement, the capacity and remaining life of the proposed asset, and any other documentation reasonably requested by Delmarva to facilitate the assessment. CEA believes that such items would minimally include:

- Current ownership structure of respondent entity as well as its parent
- List of all generation resources owned by the respondent entity and proportion of ownership
- Megawatt capacity of each generation resource owned by respondent and its proportion of ownership
- Remaining life of generation asset proposed
- Audited financial statements and notes thereto for the preceding two years

The adverse effects of consolidation of the project entity into Delmarva's books. First, the total debt of the project would be added to Delmarva's books without any incremental revenue. This would have obvious and significant credit implications. Second, significant unpredictability would be introduced into Delmarva's financial statements as a result of having to reflect on Delmarva's books the operations of a large power project that is outside of Delmarva's control.⁷²

⁷¹ Delaware Commission's Independent Consultant Report, Initial Report Regarding Delmarva Power & Light Company's Proposed RFP, September 18, 2006, at 20.

⁷² Tyson, op. cit., p. 20.

The financial risk imposed on Delmarva by FIN 46 is a risk that Delmarva refuses to assume as it has clearly stated in its threshold requirements to the RFP. It appears that all parties are largely sympathetic to Delmarva's concerns and are in agreement in this regard.

However, although there is agreement disqualifying bids that trigger FIN 46 accounting treatment at the outset of the PPA, Delmarva remains exposed to the risk that a *subsequent* designation of primary beneficiary, triggering FIN 46 treatment, could occur during the contract period. As such, it is further incumbent on Delmarva to protect itself from such financial uncertainty by having the right to terminate the PPA after a reasonable cure period upon receiving such designation. As shown in JJR-3, other RFPs such as those issued by Georgia and Puget Sound Energy have provided these same termination rights.

VI. CONCLUSIONS AND RECOMMENDATION

Delmarva's recommended RFP, term sheets and bidder evaluation criteria were created with a first-hand understanding of Delmarva's specific load requirements, corporate structure and financial vulnerabilities. The recommendations of the Independent Consultant dilute many of these considerations, in particular with regard to bidder acceptance, bid evaluation and security, opening Delmarva to substantial and unnecessary risk. These risks include long-term contract risk, counterparty risk, market risk, customer migration risk and ultimately liquidity and bankruptcy risk. There are a substantial number of recent examples of energy and utility companies that accepted one or more of these risks, resulting in significant losses when market forces turned against them.

In order to protect Delmarva and its customers, CEA recommends that Delmarva's acceptance of risk in the proposed RFP and PPA terms should be aligned with its specific situation. Specifically, but not to the exclusion of other provisions that may be proposed by Delmarva, we recommend that the Delaware Commission adopt Delmarva's proposed formula for calculating operating security requirement without any cap on the amount of the posted security; accept Delmarva's proposed use of a 50% imputed debt risk factor; and accept Delmarva's proposed information requirements for bidders with respect to VIE and proposed termination rights in the event of a determination that the PPA counterparty is a VIE under FIN 46.

RFP Term Comparison - Imputed Debt

Key Terms RFP	General Description	Imputed Debt
Public Service of Oklahoma	2005 RFP for peaking capacity	Imputed debt calculation at 30% and 50% risk factors. Bid evaluation will include the imputed cost (revenue requirement) of additional common equity to maintain current debt-equity ratio.
Georgia Power	RFP for 1,200 MW baseload or immediate capacity, and intermediate (7-15 year) or long term (30 year)	Imputed debt calculation at 30% risk factors. Bid evaluation will include the imputed cost (revenue requirement) of additional common equity to maintain current debt-equity ratio.
NIPSCO	2006 All Source RFP	Imputed debt calculation at 30% risk factors. Bid evaluation will include the imputed cost (revenue requirement) of additional common equity to maintain current debt-equity ratio.
PacifiCorp	2006 RFP for 2012 baseload resources	Imputed debt calculation at 50% risk factors. Bid evaluation will include the imputed cost (revenue requirement) of additional common equity to maintain current debt-equity ratio. (See Excerpt from RFP at JJR-1.a.)
Puget Sound Energy	RFP All-Generation Resource RFP for 1,000 MWs (winter 2006/2007) to over 1,600 MW by 2015.	Imputed debt calculation at 30% risk factors. Bid evaluation will include the imputed cost (revenue requirement) of additional common equity to maintain current debt-equity ratio.
SWEPCO	RFP for up to 500 MW short term peaking capacity and up to 1,600 MW long-term generation (peaking, intermediate, and baseload) by 2011.	Imputed debt calculation at 30% and 50% risk factors. Bid evaluation will include the imputed cost (revenue requirement) of additional common equity to maintain current debt-equity ratio.
Public Service Company of Colorado	2004 RFP for dispatchable resources for 10 year period	PSCO plans to estimate the cost of the debt equivalent of each long-term power purchase agreement.
Cleco	2004 RFP for capacity and energy resources	Imputed debt calculation at 40% risk factors. Bid evaluation will include the imputed cost (revenue requirement) of additional common equity to maintain current debt-equity ratio.

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2012 Request for Proposals Base Load Resources

PacifiCorp
Draft RFP 2012
Responses due January 2007

economic life (both initial and remaining), the fair market value, executory costs, nonexecutory costs, and investment tax credits or other costs (including debt specific to the asset being proposed) associated with the Bidder's proposal. Financial data contained in the Bidder's financial statements (e.g., income statements, balance sheets, etc.) may also be required to provide additional information.

A SFAS No. 13 Form (Appendix F) must be completed to the extent the Bidder submits a proposal which results in either direct or inferred debt.

Cost Associated with Direct or Inferred Debt

PacifiCorp will take into account a cost associated with direct or inferred debt as part of its economic analysis in the initial screening.

- **Direct debt** results when a contract is deemed to be a Capital Lease pursuant to EITF 01-08 and SFAS No. 13 and the lower of the present value of the nonexecutory minimum lease payments or 100% of the fair market value of the asset must be added to PacifiCorp's balance sheet.
- **Inferred debt** results when credit rating agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing PacifiCorp's credit standing.

In both instances, PacifiCorp would need to inject equity to maintain the same debt/equity ratio as before the power supply contract. Since equity has a cost, this cost will be taken into account when evaluating the bids to determine the short list.

For the purposes of RFP 2012, PacifiCorp will determine the amount of debt associated with each bid that would result in an applicable contract, derive the associated equity infusion, then include in its analysis the cost associated with the equity amount multiplied by the pre-tax difference between Return on Equity ("ROE") and PacifiCorp's Weighted Average Cost of Capital ("WACC"). Pre-tax ROE will be assumed to be equal to 16.92% and pre-tax WACC will be assumed to be 11.48%. The amount of debt will be the higher of the direct or inferred debt. This will be updated prior to the issuance of the final RFP 2012.

Direct debt will be determined for each year as of the beginning of the contract as the amount PacifiCorp must place on its balance sheet as a result of a Capital Lease. If the bid does not result in a Capital Lease then the amount of direct debt will be zero.

Inferred debt will be determined by utilizing the methodology used by Standard & Poor's in the article attached as Attachment 12. At the beginning of the contract, the net present value of the remaining fixed payments will be calculated using a 10% discount rate and then multiplied by a "risk factor." The risk factor will be 50%.

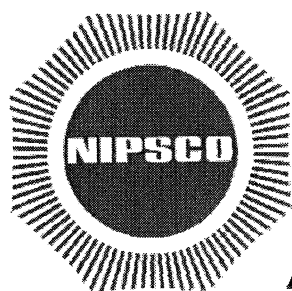
RFP Term Comparison - Operational Security Caps

Key Terms RFP	General Description	Caps on Operating Security
Pubic Service of Oklahoma	2005 RFP for peaking capacity	None noted (Security provisions require credit protection for capacity at contract price and for mark to market losses on energy for 18 month window).
Georgia Power	RFP for 1,200 MW baseload or immediate capacity, and intermediate (7-15 year) or long term (30 year)	Minimum performance security requirement set at staggered \$/kW thresholds, based upon term of PPA and operational phase of PPA within its respective life.
NIPSCO	2006 All Source RFP	None noted. (See Excerpt from RFP at JJR-2.a.)
PacifiCorp	2006 RFP for 2012 baseload resources	Maximum credit assurance based on credit rating and MW capacity according to matrix.
Puget Sound Energy	RFP All-Generation Resource RFP for 1,000 MWs (winter 2006/2007) to over 1,600 MW by 2015.	None noted. (See Excerpt from RFP at JJR-2.b.)
SWEPCO	RFP for up to 500 MW short term peaking capacity and up to 1,600 MW long-term generation (peaking, intermediate, and baseload) by 2011.	None noted (Security provisions require credit protection for mark to market losses for 18 month window).
Public Service Company of Colorado	2004 RFP for dispatchable resources for 10 year period	\$125/kW cap on collateral. Buyer retains subordinated lien on facility.
Cleco	2004 RFP for capacity and energy resources	None noted (Security provisions require credit protection for mark to market losses for 18 month window).

NIPSCO 2006 All Source RFP

Issued June 1, 2006

Northern Indiana Public Service Company's
2006 All Source
Request for Proposals
June 1, 2006
Revision 1.0



A NiSource Company

to verify continued operation and maintenance of the Proposal for the applicable term.

- Proposals will comply with all applicable MISO requirements.

2.1.4 Credit and Security Requirements

NIPSCO requires credit support and security requirements that will provide protection in the event that a Bidder breaches or fails to perform under any agreement arising from this RFP. Performance Security will address the risk associated with both the completion of a new facility to deliver capacity on the scheduled delivery date and the contracted deliveries throughout the duration of the contract.

Bidder shall provide Performance Security. The amount of the security deposit will be negotiated and will be determined based upon the specific Proposal characteristics and the potential risk of contract default. NIPSCO will consider Performance Security mitigating factors such as, but not limited to; subordinate liens on project assets and step-in rights. Bidders shall set forth their proposal for Performance Security and mitigating factors on APPENDIX 5 Financial Information Form 2.3.

Performance Security must be posted upon execution of the Master Power Purchase and Sale Agreement or other agreement satisfactory to NIPSCO and remain in place throughout the duration thereof.

Based on the Bidder's credit quality and tangible net worth, the amount of the Performance Security will vary. Performance Security must be provided in the form of cash or cash equivalents (U.S. Dollars or U.S. Government Bonds) deposited with an Issuer acceptable to NIPSCO ("Deposits"), an irrevocable standby letter of credit drawn on an Issuer acceptable to NIPSCO ("Letter of Credit"), and/or a company guarantee from an investment-grade rated entity. The Credit Limit in Table 2-1 Bidder Credit Limit shows the maximum unsecured credit that NIPSCO will apply towards or Guarantor's required Performance Security. A Bidder Credit Limit will be calculated for each Bidder or Guarantor of Bidder based on the company's senior unsecured debt rating and tangible net worth set forth in Table 2-1. For non-public companies, NIPSCO will determine a credit score as defined in Section 2.7.2.5.

Table 2-1 Bidder Credit Limit

Unsecured Debt Rating	Credit Limit
AAA/Aaa to AA-/aA3	\$ 50,000,000
A+/A1 to A-/A3	\$ 40,000,000
BBB+/Baa1 to BBB-/Baa3	\$ 25,000,000
Below BBB-/Baa3	\$ 0



A minimum of 10% of the Performance Security must be provided in the form of Deposits and/or a Letter of Credit. The remaining Performance Security shall be in the form of a company guarantee from an investment-grade rated entity, Deposits, and/or a Letter of Credit. Performance Security in excess of the Bidder Credit Limit shall be in the form of Deposits and/or a Letter of Credit. The Bidder Credit Limit shall be recalculated and the form of Performance Security adjusted based on the Bidder's most recent fiscal year end audited financial statements or within 5 business days of the Bidder becoming aware of any change in the Bidder's senior unsecured debt rating.

2.2 Confidentiality

NIPSCO will take reasonable precautions as it would with its confidential information and use commercially reasonable efforts to protect any claimed proprietary and confidential information contained in a Proposal; provided that such information is clearly identified by the Bidder as "PROPRIETARY AND CONFIDENTIAL" on the page on which proprietary and confidential material appears. This notwithstanding, NIPSCO may release such information: (1) to any external contractors for the purpose of evaluating Proposals, but such contractors will be required to observe the same care with respect to disclosure as NIPSCO; and to others who have a need for such information for purposes of evaluating the RFP, the RFP process or the agreement resulting from the RFP process, including but not limited to the Indiana Utility Regulatory Commission, its employees, staff, consultants and/or agents or (2) if NIPSCO is requested or compelled to disclose such information (or portions thereof) (i) pursuant to subpoena or other court or administrative process; (ii) at the express direction of any agency with jurisdiction over NIPSCO, or (iii) as otherwise required by law. If NIPSCO determines that the release of such information will be made under one of the circumstances set out above, NIPSCO will provide Bidder with written notice. NIPSCO holds no duty or requirement to Bidder to withhold such information if it is so requested as described above.

If a Bidder requires greater assurances of confidentiality in connection with its Proposal, a form of confidentiality agreement is provided in APPENDIX 1.

NIPSCO will take all commercially reasonable steps to ensure that all Bidders have access to the same information from NIPSCO without any undue preference or discrimination.



RFP Term Comparison - VIE Treatment / FIN 46

Key Terms RFP	General Description	VIE Treatment / FIN 46
Public Service of Oklahoma	2005 RFP for peaking capacity	Company will not accept bids that require consolidation under FIN 46.
Georgia Power	RFP for 1,200 MW baseload or immediate capacity, and intermediate (7-15 year) or long term (30 year)	Company will not accept bids that require consolidation under FIN 46. If PPA causes the Companies to be subject to VIE treatment at any point during the term of the PPA, unless cured, constitutes seller default under the PPA. (See Excerpt from RFP at JJR-3.a.)
NIPSCO	2006 All Source RFP	Company will not accept bids that require consolidation under FIN 46.
PacifiCorp	2006 RFP for 2012 baseload resources	Company will not accept bids that require consolidation under FIN 46. If PPA causes the Companies to be subject to VIE treatment at any point during the term of the PPA, unless cured, constitutes seller default under the PPA. (See Excerpt from RFP at JJR-3.b.)
Puget Sound Energy	RFP All-Generation Resource RFP for 1,000 MWs (winter 2006/2007) to over 1,600 MW by 2015.	Bidders must provide detailed financial information for determination of applicability of FIN 46R. PSE will assess applicability and financial statement impact.
SWEPCO	RFP for up to 500 MW short term peaking capacity and up to 1,600 MW long-term generation (peaking, intermediate, and baseload) by 2011.	Company will not accept bids that require consolidation under FIN 46.
Public Service Company of Colorado	2004 RFP for dispatchable resources for 10 year period	Not Addressed.
Cleco	2004 RFP for capacity and energy resources	Not Addressed.

APPROVED FORM
July 5, 2005

Version No. 5

**Georgia Power Company
and
Savannah Electric and Power Company
2009
REQUEST FOR PROPOSALS**

July 5, 2005

Introduction

Georgia Power Company and Savannah Electric and Power Company (collectively the "Companies") issue this Request For Proposals ("RFP") to acquire new supply-side resources beginning June 1, 2009. This RFP is governed by the Georgia Public Service Commission's ("GPSC") Rules 515-3-4-.04(3) (the "RFP Rules"). Bidders should note that the GPSC is utilizing an Independent Evaluator ("IE"), Accion Group, as the point of contact with bidders in this solicitation. All disputes, questions or comments should be referred to the IE. All bidders should familiarize themselves with the RFP Rules, a copy of which is located on the IE's website at www.gpsc.ie.com.

Southern Power Company ("Southern Power"), an affiliate of the Companies, may submit bid proposals in response to this solicitation. The Companies are complying with the "RFP Rules" which incorporates measures to segregate the Companies' Evaluation Team and Southern Power's Bid Team. The Companies have implemented specific controls to ensure that Evaluation Team and Bid Team RFP-related information is confined to the appropriate Team, recognizing that there are certain limited instances where the Companies and Southern Power share certain services. Additionally, prior to receipt of bids, the Companies are implementing process steps to ensure that all bids from affiliates and non-affiliates are evaluated using a common methodology and applied in a manner that ensures that the affiliate receives no advantages in the evaluation.

The current projection of the Companies' needs is in the range of approximately 1,200 MW. The current GPSC-approved Integrated Resource Plan ("IRP") reflects the proposed addition of both gas fired combined cycle and simple cycle combustion turbine facilities. Attachment H is a redacted template for information that the Companies believe may be helpful in submitting a proposal. The information includes current need projections and capacity factor projections for gas fired resources at various heat rates. Bidders are encouraged to obtain a copy. For a bidder to obtain the trade secret information, it is necessary to complete the confidentiality agreement in Attachment I, and submit it to the IE. The trade secret information will be available by July 5, 2005. This IRP projection does not foreclose bidders from submitting bid proposals for any type of resource (base load, intermediate, or peaking) utilizing any type of energy source including but not limited to coal, nuclear, oil, natural gas, biomass, wind, solar, and

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July 5, 2005

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Bid Evaluation

Bid proposals submitted pursuant to this RFP (including any submitted by the Companies' affiliates) will be considered and evaluated together. Such evaluation will include a review of transmission and ancillary service requirements, as appropriate, to determine the total cost impacts. The Companies will utilize a "target price" screen in this solicitation to ensure that the best bids received will provide value to customers. In the event that the bids received by the Companies pursuant to this RFP do not compare favorably with the target price, then the Companies may develop a self-build project proposal for comparison with the proposals received pursuant to this solicitation. Should the Companies determine that the self-build project proposal is more favorable than the best bids received as a result of this solicitation, the Companies will provide such proposal to the GPSC, along with the results of the RFP. The Companies will provide a recommendation to the GPSC as to how they would propose to proceed with fulfillment of their capacity and energy needs identified in this RFP and will seek direction from the GPSC in this regard.

At the conclusion of the evaluation, successful bidders will be contacted for negotiations that may lead to the execution of a PPA. Please note that the Companies may revise their capacity need forecast to reduce, eliminate, or increase the amount of power sought, or change the schedule for this RFP, at any point during the RFP process or negotiations. Further, this RFP and the documents are subject to modification or withdrawal at any time in the sole discretion of the Companies.

Given the length of the terms that PPA proposals may cover in response to this RFP, accounting and tax rules may require either (i) that a PPA be accounted for by the Companies as a Capital Lease¹ or operating lease, or (ii) that the seller under the PPA be consolidated, as a Variable Interest Entity², onto the Companies' books. Because the Companies are unwilling to be subject to accounting or tax treatment that results from VIE treatment, all bidders are required to certify using the form attached hereto in Attachment J, that none of their proposals will require the Seller at any time over the proposed PPA term to deconsolidate on its books and records any assets, liabilities, cash flow, profits, or losses where either of the Companies are determined to be the primary beneficiary. In the case of every successful proposal for all PPA terms, at PPA execution, an additional certification must be provided by an independent accounting firm acceptable to the Companies. Further, any PPA that the Companies execute will require that (i) seller covenant that the Companies will not be subject to VIE treatment at any point during the term of the PPA, and (ii) in the event that the PPA causes the Companies to be subject to VIE treatment at any point during the term of the PPA, unless cured, such treatment will constitute a seller event of default under the PPA.

¹ "Capital Lease" - shall have the meaning as set forth in the Statement of Financial Accounting Standards (SFAS) No. 13 as issued and amended from time to time by the Financial Accounting Standards Board.

² "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 (Revised December 2003) as issued and amended from time to time by the Financial Accounting Standards Board.

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Attachment J

**CERTIFICATION OF WHETHER PURCHASE TRANSACTION
WILL REQUIRE DECONSOLIDATION BY SELLER
WITH RESPECT TO VARIABLE INTEREST ENTITY**

PROPOSAL--_____

The undersigned individual, being the Chief Financial Officer of _____ and having responsibilities for financial accounting matters arising from the potential execution of a Purchased Power Agreement by _____ ("Seller") resulting from the acceptance of this proposal by the Companies, hereby certifies that the transaction resulting from this proposal most likely WILL (____)/WILL NOT (____) require the Seller, at any time over the proposed PPA term, to deconsolidate on its books and records any assets, liabilities, cash flow, profits or losses where either of the Companies are determined to be the primary beneficiary. My determination of the most likely accounting treatment of this transaction results from my personal consideration of FASB Interpretation Number 46(R), Consolidation of Variable Interest Entities, and the following factual matters:

Our accounting policies, procedures, and internal controls are sufficient to provide us with an appropriate basis for confirming the information contained herein.

_____Yes
_____No (please explain)

Seller qualifies for one of the scope exceptions listed in paragraph 4 of FASB Interpretation Number 46(R), Consolidation of Variable Interest Entities.

_____Yes (please explain)
_____No (please explain)

The PPA revenues correlate with fluctuations in Seller's operating cash flows (operating expenses).

_____Yes
_____No

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The PPA reduces variability in the fair value of Seller's assets, for example by absorbing fuel or electricity price risk.

_____ Yes
_____ No

The PPA term is for greater than 50% of the remaining economic life of the unit.

_____ Yes
_____ No

The PPA is for substantially all of the proposed Seller's productive output.

_____ Yes
_____ No

The Companies and/or their affiliates participated significantly in the design or redesign of the proposed Seller's generating facility.

_____ Yes
_____ No

The generating facility represents 50% or less of the fair value of the proposed Seller's total assets.

_____ Yes
_____ No

The generating facility is essentially the only source of payment for specified liabilities or specified other interest (there is specific debt associated with the generating facility).

_____ Yes
_____ No

The Bidder understands that the Companies will rely upon this certification in the evaluation of this bid proposal, that the Companies may require further documentation supporting this certification, and that the Companies reserve the right to disqualify this proposal if the Companies determine that the transaction will result in consolidation by Buyer of a Variable Interest Entity.

PacifiCorp
Draft RFP 2012
Responses due January 2007

2012 Request for Proposals Base Load Resources

PacifiCorp
Draft RFP 2012
Responses due January 2007

5. Accounting

All contracts proposed to be entered into as a result of this RFP 2012 will be assessed by the Company for appropriate accounting and/or tax treatment. Bidders shall be required to supply the Company with any and all information that the Company reasonably requires in order to make such assessments.

Specifically, given the term lengths that PPA, TSA, and/or exchange proposals may cover in response to RFP 2012, accounting and tax rules may require either: (i) a contract be accounted for by PacifiCorp as a Capital Lease or Operating Lease³ pursuant to SFAS No. 13, or (ii) the seller or assets owned by the seller, as a result of an applicable contract, be consolidated as a Variable Interest Entity⁴ (VIE) onto PacifiCorp's balance sheet. To the extent a Bidder proposal results in an applicable contract, the following shall apply with respect to VIE treatment:

- The Company is unwilling to be subject to accounting or tax treatment that results from VIE treatment. As a result, all Bidders are required to certify, with supporting information sufficient to enable the Company to independently verify such certification, that none of their proposals will subject the Company to such VIE treatment. Bids that result in VIE treatment will be rejected.
- Further, any applicable contract that the Company executes will require that: (i) the Seller covenant that the Company will not be subject to VIE treatment at any point during the term of the agreement, and (ii) in the event that the contract causes the Company to be subject to VIE treatment at any point during the term of the agreement, unless cured, such treatment will constitute a seller event of default.

Each Bidder must also declare, in each of its proposals, whether or not each such proposal will subject the Company to Capital Lease treatment or Operating Lease treatment pursuant to SFAS No. 13. In any case for which the Bidder declares that the proposal will subject the Company to lease treatment pursuant to SFAS No. 13, after application of Emerging Issues Task Force ("EITF") 01-08 ("Determining Whether an Arrangement Contains a Lease"), the Bidder is required to certify such declaration (Capital Lease or Operating Lease), with supporting information sufficient to enable the Company to independently verify the Bidder's opinion of how the Company will be required to account for the proposal.

Each Bidder must also agree to make available at any point in the bid evaluation process, any and all financial data associated with the Bidder, the Facility and/or the PPA, TSA or other contract that PacifiCorp requires to independently verify the Bidder's accounting declarations or certifications required above. Such information may include, but may not be limited to, data supporting the

³ "Capital Lease" and "Operating Lease" - shall have the meaning as set forth in the Statement of Financial Accounting Standards ("SFAS") No. 13 as issued and amended from time to time by the Financial Accounting Standards Board.

⁴ "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in Financial Accounting Standards Board ("FASB") Interpretation No. 46 (Revised December 2003) as issued and amended from time to time by the FASB.

Attachment B

Delmarva Power's Proposed Language

Delmarva Power & Light

Supplemental Exhibit 1 - Proposed Language Credit / Security Issues

The Security Provisions Proposed By the Independent Consultant Are Inadequate Given the Heightened Default and Operating Risks

Acute and “Uncapped” Risks for SOS Customers and Delmarva

- Delmarva has \$650 million in equity capital, relative to a total estimated \$750 million capacity obligation.
- Delmarva is rated BBB-/Baa2, one step away from non-investment grade.
- Unlike other markets referenced in the Consultant’s report, Delmarva’s market is fully competitive – customers **will** migrate if market prices fall.
- Delmarva lacks the corporate structure and resources to adequately manage the variability and risk of a 400MW unit-specific, unit-contingent contract.

Many of the recommendations in the Consultant Report will subject Delmarva and its customers to substantial and unnecessary risk if they are incorporated in the final RFP. Below is a summary of the primary risks that are brought to the RFP by the recommendations of the Independent Consultant, along with the possible effects on Delmarva and its customers if these risks are realized:

Real Risks to Customers and Delmarva

Examples where utilities and customers have absorbed risks / costs include:

- **Niagara Mohawk – Absorbed Long-term Contract Risk:** Restructured out-of-market contracts at a **cost of \$3.9 billion** in cash and **20.5 million shares of stock** in payment to the IPPs.
- **Enron’s Counterparties – Absorbed Enron Credit Risk:** The well-known Enron bankruptcy **cost its counterparties an estimated \$6.3 billion**, including \$900 million related to contracts with energy companies.
- **PG&E NEG – Absorbed Liquidity Crisis Risk:** A series of short-term debt payments combined with an over-supply of merchant generation to push NEG into a liquidity crisis and ultimately into bankruptcy in 2003.
- **California Utilities – Absorbed Customer Migration Risk:** More than 15% of the State’s load had migrated to contracts with competitive suppliers in the two years following retail access in May 1998. However, as high market prices in 2000 and 2001 **cost these suppliers hundreds of millions of dollars**, these providers elected to pursue a strategy of returning their customers to the utilities. This left the utilities having to shoulder the cost of purchasing energy at extremely high prices in order to serve this load.

Staff's Proposal

107. We agree with and approve the IC's recommendation that Operational Period Security be capped at \$200/kW. We are sympathetic to the claims of participants that this required security is on the high side, but none has argued that it is commercially unreasonable. In light of our decision not to require bidders to be investment grade and that Operational Period Security will be capped (both of which DP&L opposed), we believe that it would be reasonable to require security on the higher side in this context. We reject DP&L's position that Operational Period Security should be uncapped because such a provision is not prevalent in the industry for long-term contracts and, if included, we believe it is likely that bid participation would be impaired because of the negative effect such a provision may reasonably have on financing. **(VOTE)**

Delmarva's Proposal

107. We agree with and approve Delmarva's recommendation that the seller should be required to post uncapped security in the form of a letter of credit or similar security to cover damages over a two-year period and we reject the IC's position that such security should be capped. We recognize that posting this security will be a burden to participants. However, the security is only required when the contract price is below market. Further, the security only covers a period of two years, not the remaining life of contract. As such, it properly ensures, in event of seller default and albeit for that limited period, that SOS customers will at least receive the benefit of the contract price being below market. As to remaining life of the contract, which could be up to 23 years, SOS customers will have uncapped exposure and no recourse to a seller letter of credit to offset that exposure. Thus, it reasonable to at least require the seller to post uncapped security to cover a period of two years. Further, none of the participants have demonstrated that this limited security requirement is commercially unreasonable. In fact, Delmarva presented evidence in the form of the RFP Term Comparison that demonstrates that uncapped security is not unusual. The absence of a cap in other RFPs apparently did not prevent bid participants from obtaining financing and should not do so here. Delmarva's first lien in 30% of the project as proposed by the IC, with lenders having a first lien in the remaining 70% of the project, will provide supplemental security to the two-year uncapped letter of credit. (VOTE)

Delmarva Power & Light

Supplemental Exhibit 2 - Imputed Debt Adjustment Update

Imputed Debt Offset

The concept of imputed debt has risen to prominence largely as a result of the increased use of off-balance-sheet financing. Although the use of off-balance sheet leases has declined, rating agencies have continued to focus on the long-term obligations of creditors that are largely debt-like in character, including PPAs. In general, Standard & Poors “applies a 0 to 100% risk factor to the net present value of the PPA capacity payments, and designates this amount as the debt equivalent.” The actual percentage applied depends on how much the capacity payment commitment resembles the credit risk characteristics of long-term debt. Standard & Poors sets a *minimum* imputation rate of 30% for “utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased power costs.”

This 30% should be interpreted as a *baseline* multiplier, applicable only to utilities with a diversified supply portfolio. Higher percentages are applied when the contract has a long term, is tied to an individual seller, is a “take-or-pay” commitment that is not tied to performance of the unit, and/or if the contract is out-of-market. In addition, S&P warns that “if a utility relies on any individual Seller for a material portion of its energy needs, the risk of non-delivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.” Delmarva will rely heavily on an individual seller under its RFP, and non-delivery risk is very real.

In fact, the proposed PPA will likely have all of the attributes discussed above. It will have a long term (10-25 years), it will be tied to an individual seller and will therefore have non-delivery risk, it has attributes of a take-or-pay commitment to the extent that a capacity component is bid, and it will likely be priced above market in the initial years for reasons discussed in Section II. For these reasons, a 50% offset factor is consistent with S&P and Moody’s guidelines and is fully warranted.

Assuming \$6.0 billion in capacity payments as noted above, and a 50% risk factor is used, an imputed debt value of over \$775 million would be effectively added to Delmarva’s debt in its future credit reviews. This commitment dwarfs the \$516 million in total long-term debt currently on Delmarva’s balance sheet, and would create total debt at Delmarva of nearly \$1.3 billion. As a result, the interest and debt service coverage ratios used as key credit metrics by the rating agencies would be approximately cut in half. Absent a large infusion of equity (and perhaps even with such an infusion) this would cause a significant deterioration in Delmarva’s credit rating, especially given Delmarva’s current precarious credit standing. In turn, the jeopardized credit rating will put upward pressure on Delmarva’s cost of debt and access to capital. For the reasons discussed above, Delmarva is fully justified in using *at least* a 50% imputed debt offset in the price factor of its bid evaluations.

Delmarva Power & Light
Supplemental Exhibit 2 - Imputed Debt Adjustment Update
Page 2

Staff's Proposal

145. We agree with and approve the IC's recommendation. The EURCSA provides that DP&L will be permitted rate recovery of PPA costs. In addition, DP&L is a distribution utility. Based on the written guidance provided by S&P and Moody's and the precedents established in other jurisdictions, we believe it is reasonable not to incorporate an imputed debt offset in the economic evaluation but to include a 30% risk factor in a sensitivity analysis. We note that a 30% risk factor appears more apt than a 50% risk factor in light of the relevant EURCSA provisions and DP&L's role as a distribution utility as opposed to a vertically integrated utility. We also do not believe that it would be appropriate to include the imputed debt offset as a factor in the bid evaluation, as we believe this could provide a DP&L self-build option with an advantage that may not be justified. Thus, we agree with the IC. (Unanimous).

Delmarva Proposal

145. We approve the IC's recommendation in part and Delmarva's recommendation in part. The EURCSA provides that DP&L will be permitted rate recovery of PPA costs. Accordingly we add an automatic true-up mechanism to the contract to reflect actual debt rates and PPA costs. Based on the written guidance provided by S&P and Moody's and the precedents established in other jurisdictions, we believe it is reasonable to incorporate a 30% imputed debt offset in the economic evaluation and to include a 50% risk factor in a sensitivity analysis. (Vote).